Class III Mid-Term Project - Cooperative Agreement No. DE-FC22-95BC14939

"Increasing Heavy Oil Reserves In The Wilmington Field Through Advanced Reservoir Characterization And Thermal Production Technologies"

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Title: "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam"

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Abstract

This paper will discuss a competitively-priced and superior well completion technique for controlling unconsolidated sand formations by injecting high temperature and pressure steam to geochemically bond the sand grains in the perforation tunnels. Wells applying this method are cased and cemented through the desired producing interval and completed with only a few small diameter perforations. This well completion technique has been applied in 12 horizontal wells and 22 vertical wells with over 90% of the wells capable of production or injection after two years.

The use of the hot alkaline / steam sand consolidation technique to complete wells is based on the geochemical bonding of unconsolidated formation sand grains with a lattice of primarily high temperature complex synthetic silicate cements and possibly other lower temperature precipitates such as silica cements and carbonate scales. The complex silicate cements and other mineral precipitates are created by the high temperature and high alkaline pH steam condensate which preferentially dissolves sand grains with high specific surface area. The injected fluids rapidly lose heat to the formation and various cements precipitate with changes in temperature, alkalinity, and contact time. The lattice of cement bonds are created by the relatively high volume and high velocity steam vapor phase which dissipates through the near-wellbore region quickly and carries away excess cements and other precipitates where they do not adversely affect formation porosity and permeability.

The wells completed with this technique have equivalent or higher productivity and injectivity than wells completed with opened-hole, gravel-packed slotted-liner completions. In addition, this technology can significantly lower drilling and completion costs, improves fluid entry or injection profile control, provides a low cost means to eliminate unwanted completion intervals, and provides flexibility to use the wells interchangeably as producers or injectors.

This study is part of the U.S. Department of Energy Class III Reservoir Program to improve oil recovery in Slope and Basin Clastic (SBC) reservoirs.

Introduction

Thermal recovery operations in the Wilmington Field have met with operational difficulties peculiar to its geology. Thermal operations have been subject to premature well and downhole equipment failure as a result of early steam breakthrough and sanding. These problems are commonplace in other Slope and Basin Clastic reservoirs with heterogeneous and unconsolidated sands. Additionally, the high reservoir pressures and associated high steam temperatures in the Wilmington

Field aggravate the wellbore completion and equipment problems associated with early steam breakthrough.

The unconsolidated nature of the turbidite sands in the Wilmington Field result in well producibility problems. Thus, a means of limiting sand production has been of paramount importance with regard to operations in the field. The conventional well completion method applied in the field involves using an opened-hole, gravel-packed and slotted liner completion. To reduce capital costs and to improve vertical injection profile control, two new vertical steam injection wells in the Fault Block II-A, Tar Zone (Tar II-A) were selected in 1990 to test a new well completion technique applying limited-entry perforating[1] with the wells cased and cemented to total depth. Three subsequent new vertical steam injection wells were given conventional perforated completions in wells cased and cemented to total depth. Engineering observed that the five steam injection wells had only minor to no sand inflow problems and suspected that a form of sand consolidation was occurring in the perforation tunnels, most likely bonding with silica cements. The alkaline hot water/steam sand consolidation technique for completing wells (henceforth called “the Sand Consolidation Technique or Treatment”) was first intentionally tested in producer well UP-779. Well UP-779 was an existing producer which was recompleted into the Tar II-A, placed on steam injection in December 1991, and performed equivalent to offset steam drive producers. The new sand consolidation technique was further tested in eight new vertical wells and two vertical well recompletions in the Tar II-A and two new horizontal wells in the Tar I using various numbers of perforations, perforation sizes, steam volumes and steam rates from 1992 – 1994. An empirical well completion process was developing, but an understanding of the actual detailed geochemistry of the sand consolidation process occurred with its application in the four DOE project horizontal wells (UP-955, UP-956, 2AT-61 and 2AT-63) in the Tar II-A in 1996. Consolidated sand samples were found encrusted to the steam injection tubing tail following a cyclic steam stimulation job in well UP-955 in October 1996. The samples showed bonding of the sand grains with high temperature cements not found in the native formation rocks, but geochemically created through the dissolution of formation minerals from the hot alkaline in the condensate phase of the steam. The success of the sand consolidation technique led to its subsequent application in six new horizontal wells and four vertical well recompletions.

The Sand Consolidation Technique has been applied for purposes other than new well completions and has proven to have other beneficial qualities. In October 1994, well UP-932 successfully underwent the technique to repair enlarged slots in its slotted liner. Well UP-932 production was restored to its previous production rates without sand production. A second well, UP-924, was successfully given a sand consolidation treatment to repair a damaged slotted liner in November 1997. Several wells with sand consolidation completions have been given hydrochloric acid jobs to successfully remove scale damage without affecting the consolidated sands. Gross fluid production rates following the HCl acid jobs typically are restored to pre-scale damaged rates.

Wells with sand consolidation completions have very high productivity for the relatively small number and size of perforations used and production and injection well rates have been equivalent to greater than wells with opened-hole gravel-packed slotted-liner completions. The sand consolidation completions can fail if produced under high differential pressures. However, these types of well failures have generally been repaired successfully by applying another alkaline hot water/steam sand consolidation treatment.

Tables 1-3 list the wells that have been given Sand Consolidation Treatments and pertinent well data including the number and size of perforations, the volume of steam used, the length of the completion interval, and the maximum stabilized injection and production rates. Table 1 lists the new vertical wells, Table 2 lists the new horizontal wells, and Table 3 lists the wells that were recompleted or had liner repairs.

Production History and Geology

The Wilmington Oil Field is the third largest oil field in the United States, based on the total oil recovered. Over 2.5 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion barrels. The field is located in and around the City of Long Beach, in Southern California. Location maps of the field are shown in Figures 1 and 2. The field is divided into ten fault blocks and seven major producing zones as illustrated in Figures 3 and 4. The Sand Consolidation Technique has been applied in wells completed into the heavy oil sands of the Tar, Ranger and Upper Terminal zones in Fault Blocks I – V, with the primary testing performed in the Tar II-A.. As such, most of the discussion will center on this area.

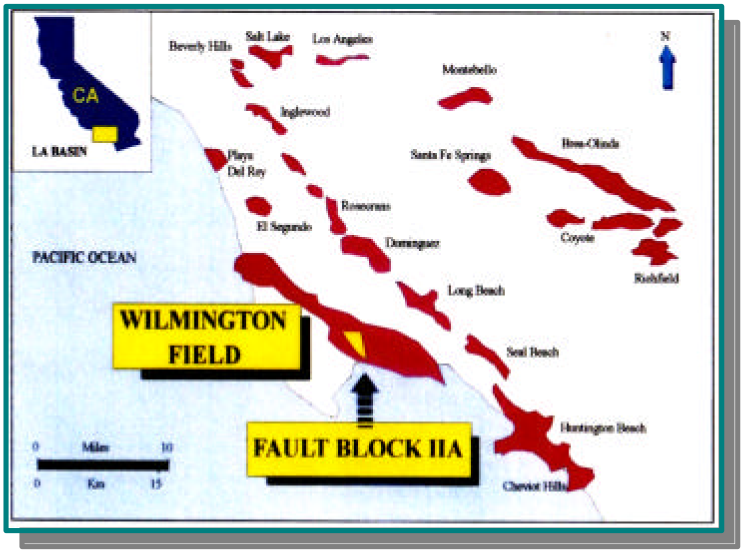


Figure 1 Map showing the geographical location of the Wilmington Field in Southern California.

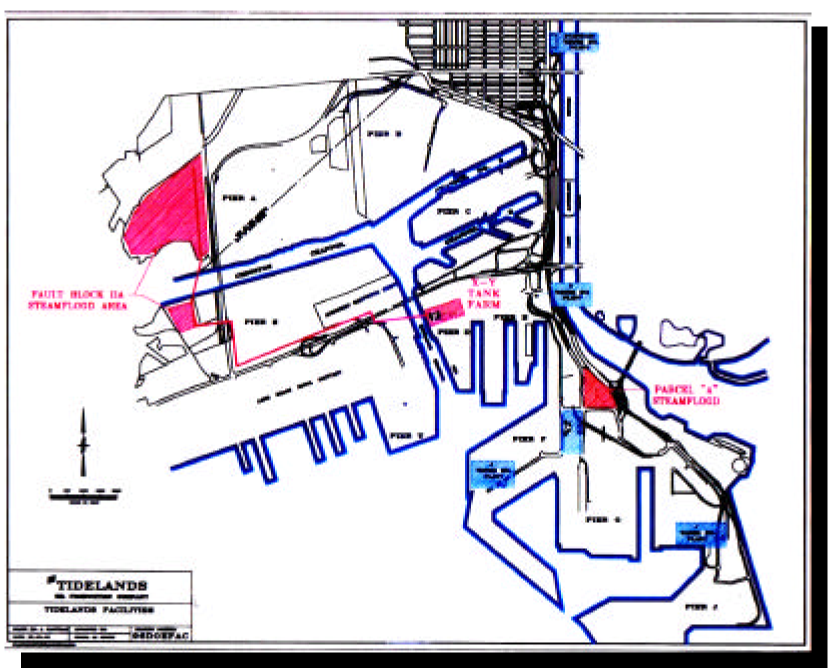


Figure 2 Plan view of Tidelands' facilities showing the steamflood areas in Fault Blocks II-A and V, Wilmington Field.

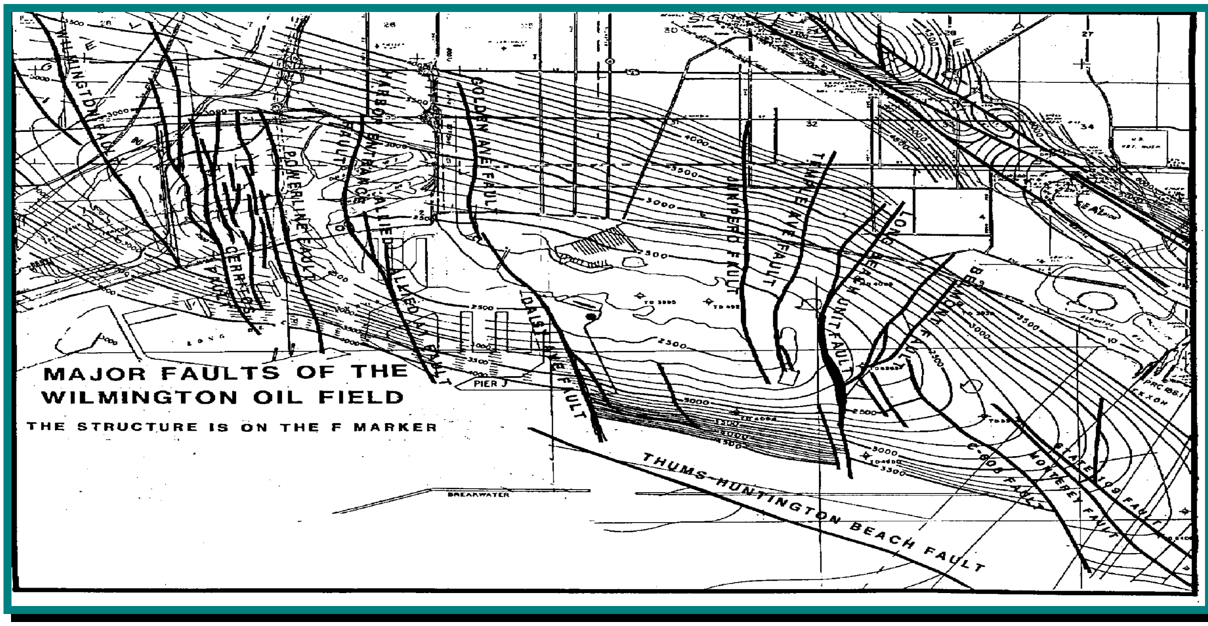
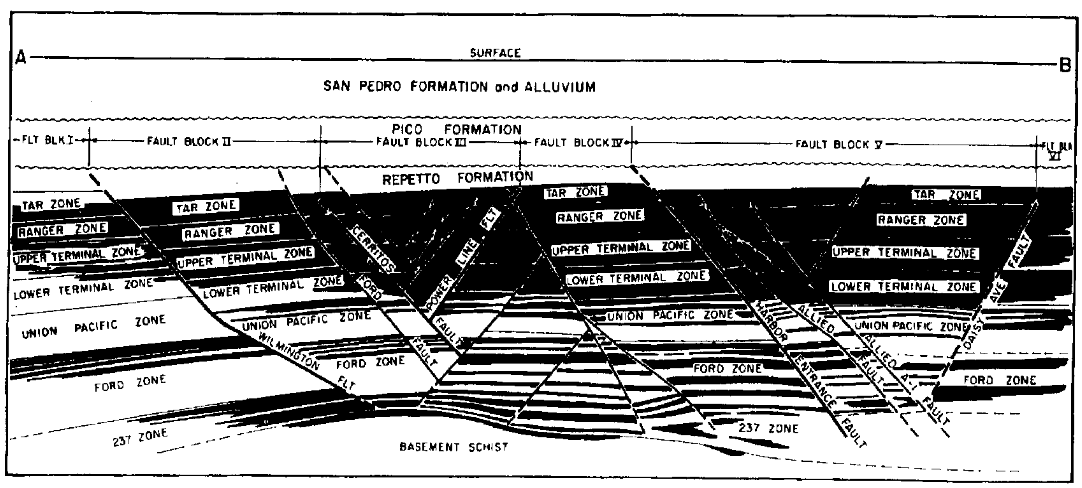


Figure 3 Geologic representation of the Wilmington Oil Field detailing fault line layout.



Northwest-southeast cross section, Wilmington field, showing producing zones. Trace of section is *A-B* on Fig. 1. Source—*California Oil and Gas Fields*, Pt. 2; courtesy California Division of Oil and Gas.

WILMINGTON FIELD, LOS ANGELES COUNTY, CALIFORNIA

Figure 4 Cross section of a representative sector of the Wilmington field detailing producing zones.

Primary production from the field began in 1936. Waterflood operations were introduced on a large scale during the 1950-60s to increase oil recovery and control surface subsidence. Various tertiary recovery projects have been tried since 1960, but with limited success. A successful steam injection pilot test, comprised of four inverted 5-acre five-spot patterns, was carried out in the Tar II-A from 1982-1989. The pilot recovered 1.1 million barrels of oil, for a recovery factor of 75% of the oil-in-place in a previously waterflooded area. The pilot was expanded to 150 acres using an inverted 7-spot pattern throughout the northern half of the fault block in 1989. The steamflood was further expanded in 1990, 1991, 1993, 1994, and 1995 to develop the remainder of the Tar II-A and to make more efficient use of the steam as the existing patterns matured.

The Wilmington Oil Field is an asymmetrical, highly faulted, doubly plunging anticline, eleven miles long and three miles wide. The productive area consists of approximately 13,500 acres. Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene and Upper Miocene age deposits. The seven zones within each fault block listed in order of increasing depth are the Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford and "237" sands. Fault Block II-A is located near the western edge of the field. It is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. The north and south limits of the fault block are governed by water-oil contacts within the individual sand members of the various zones.

The Tar zone is the shallowest oil producing formation and consists of lower Pliocene, middle Repetto formation lobe deposits. The upper Miocene Puente and lower Pliocene Repetto formations within Fault Block II-A consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathayal, slope and base-of-slope deposits. The upper Miocene sands are intercalated with shales and siltstones in the form of widespread thin turbidites. Large lobate fans dominate the Pliocene section.

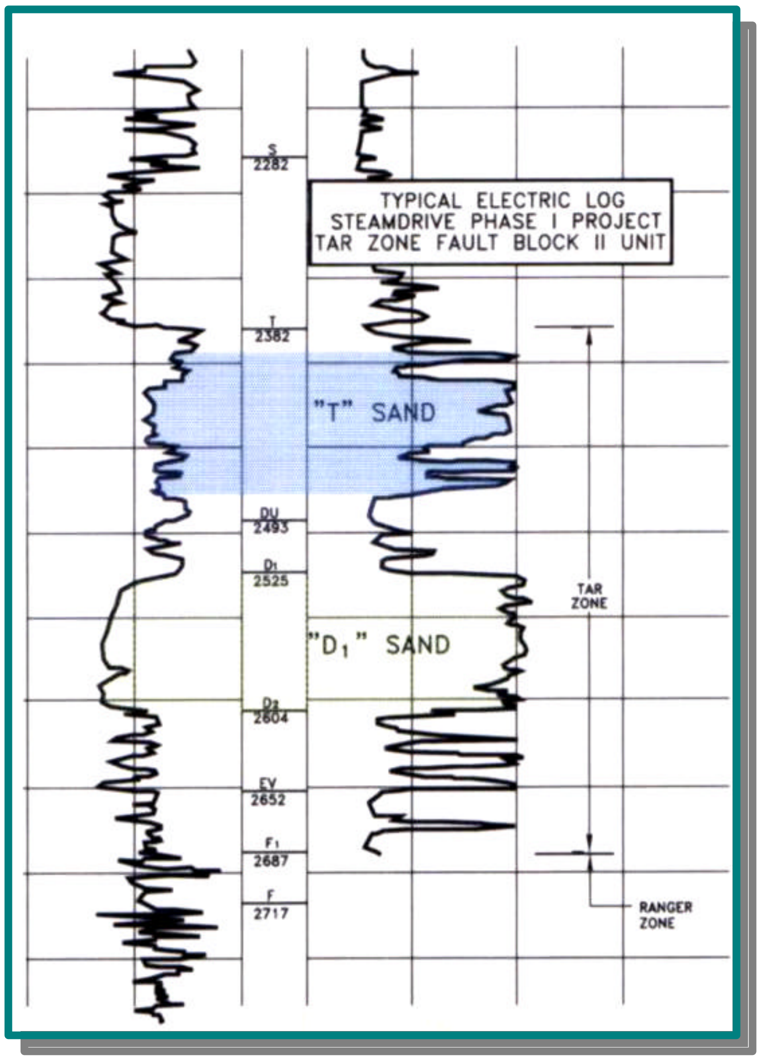


Figure 5	**Type Log 1, Tar Zone, Fault Block II-A illustrating "T" and "D1" sands.**

The Tar II-A consists of four major producing intervals exhibiting typical California-type alternation of sand and shale layers as illustrated by the type log in Figure 5. The Tar Zone reservoir sands are unconsolidated, friable, fine to medium-grained with varying amounts of silt, and comprised dominantly of subangular grains of quartz and plagioclase feldspar as shown in Figure 6. No cemented sands have been found in any of the cores taken from pre- and post-steamflood wells in the field.

The thickness of the sand layers varies from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale. The oil is of low gravity, ranging from 12-15^{o} API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 28-33% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2,330 ft below sea level in Fault Block II.

Mineral Composition of Sandstones

◆ **Quartz - SiO_2 }**	**48-50%**
Calcedony -SiO_2}	
◆ **Feldspars**	
Orthoclase - $KAlSi_3O_8$	**11-12%**
Anorthite - $CaAl_2Si_2O_8$ }	
Albite - $NaAlSi_3O_8$ }	**32-35%**
Igneous Rock Fragments}	
◆ **Mica (Biotite) - $K_2(Mg, Fe)_2(OH)_2(AlSi_3O_{10})$**	**4-6%**
◆ **Clays - Smectites, Illites, Chlorites**	**1-2%**

Figure 6 Typical Mineralogy of Tar Zone Sands

Alkaline Hot Water/Steam Sand Consolidation Procedure - A Brief Description

A well with cemented casing is first selectively perforated with ¼in. to ½in. perforations, preferably ¼in., with the number of perforations needed based on attaining limited-entry conditions[1] for the steam rates and pressures available. To minimize heat loss, thermally insulated tubing, an expansion joint and a thermal packer are run into the well. Steam quality should range from 60-80%, which provides a highly alkaline (pH = 10-12) liquid phase and the steam temperatures should be high enough (> 300^{o}C) to geochemically create the cements for bonding the sand grains. The steam rate should be high enough to achieve the critical velocities required by the limited-entry perforating theory to ensure distribution of the steam into all of the perforations. The empirically based minimum steam volume necessary to achieve sand consolidation is 750 barrels of cold water equivalent steam per ¼in. perforation.

The hot alkaline liquid phase in the 80% quality steam causes sandstone dissolution[2,3,4,5], preferentially acting on the sand grains with high specific surface area such as clays, rock fragments, and micas. As the injected fluids exit the perforations and cool, various precipitates drop out at different temperatures. The high temperature precipitates or cements bond the sand grains around the perforation tunnels and control sand movement into the wellbore. The lower temperature precipitates are driven away from the wellbore by the injected fluids, especially the steam vapor phase, where they are dispersed over enough rock volume to not cause any appreciable negative effect on formation porosity and permeability. Limited-entry perforating[1] assures that each perforation is treated with steam, that the steam is moving at maximum fluid velocities to drive off unwanted precipitates, and that the operator will have future steam injection profile control. Gross fluid rates from production wells completed with sand consolidated perforations appear to be equal to or better than wells completed with a gravel-packed liners over a similar interval. This indicates that the sand consolidation treatment is creating secondary porosity, or wormholes, through the selective dissolution of formation fines and thus increasing permeability. Many wells given a Sand Consolidation Treatment also experience higher oil cuts than offset wells. This could be attributable to the wormholes having less formation fines and therefore higher oil relative permeability. A schematic of the sand consolidation process is shown is Figure 7.

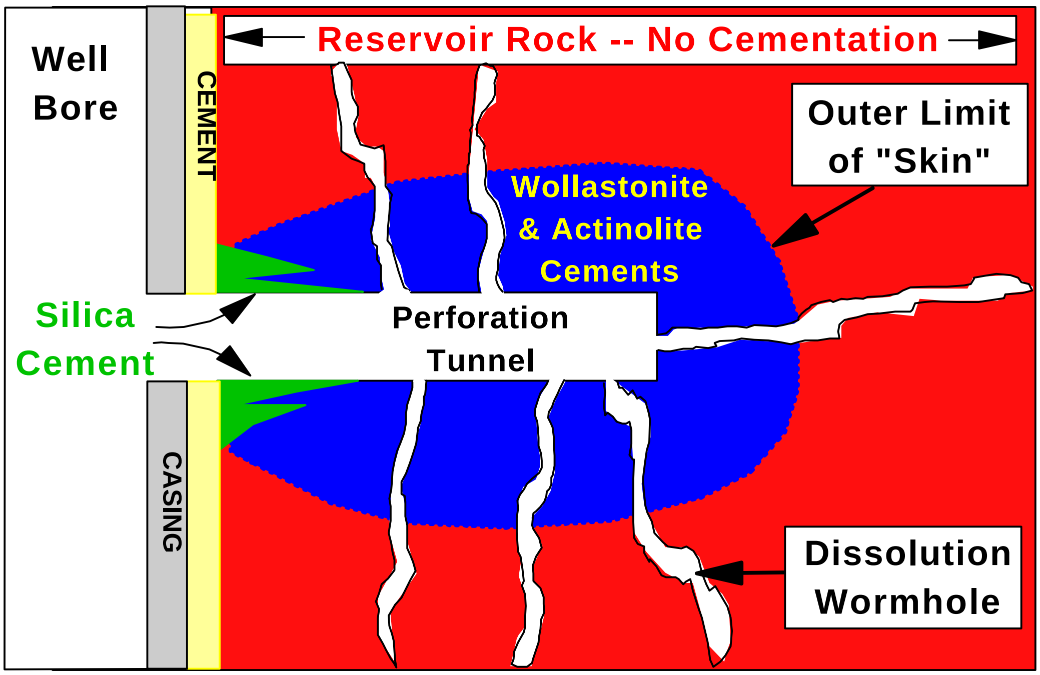


Figure 7 **Schematic representation of an ideal perforation showing distribution of synthetic cements and dissolution wormholes**

Application of Sand Consolidation Technique on UP-955

UP-955 is a horizontal steamflood well that was completed and cyclically steamed from June – October 1996. The horizontal section of the well was drilled into the "D1" Sand, within the Tar II-A, and completed using the sand consolidation technique.

The well was completed with a total of 48 perforations from 3915' to 4430', which were 0.3" in diameter. A casing scraper was then run and the casing was circulated clean with clean water. Sand consolidation began in June 1996, with the injection of 80% quality steam through insulated tubing, an expansion joint and a thermal packer set at 2398' with a tubing tail to 3907'. See Figure 8 for a wellbore diagram schematic.

The Sand Consolidation Treatment required 36,000 CWE Barrels of steam and an additional 78,000 CWE Barrels of steam were injected for the Huff "N" Puff cycle. The well was then shut-in for a 5 week steam soak. In October 1996, the insulated tubing was pulled and a coating of formation sand was found cemented to the tubing tail from 2963' to 3401'. Samples of the sand were analyzed using thin sections, x-ray diffraction and a scanning electron microscope (SEM).

The sand cemented onto the tubing tail is believed to be the result of unconsolidated sands entering the wellbore early in the cyclic steam job when the steam source underwent a shutdown on July 13 and 14. This occurred after cumulative injection was 11,500 CWE bbls of steam, approximately 30% of the volume needed to perform a successful sand consolidation on the 48 perforations. The remainder of the cyclic steam injection job proceeded without problems.

The well was placed on production in November 1996 at an initial rate of 29 BOPD and 1037 BWPD, and by March 1997, had peaked at 80 BOPD and 1450 BPD gross, with a 1700-ft fluid level over the pump. A vertical well completed over a 280-ft interval with an opened-hole, gravel-packed and slotted liner completion typically produces 1000 BPD gross. In effect, 48 – 0.3" holes were too many by a factor of two and the high fluid level hurt net oil production.

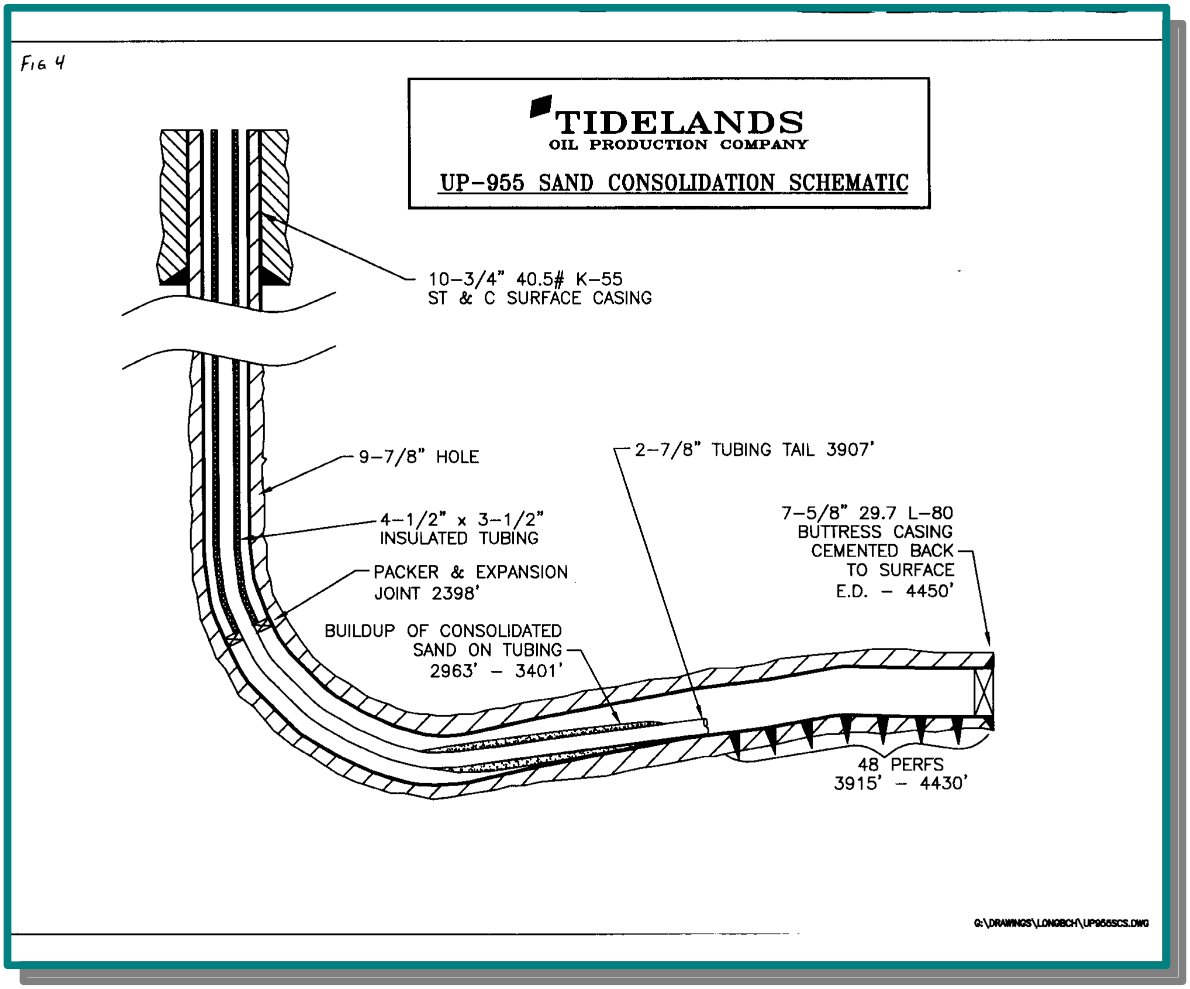


Figure 8 Wellbore Schematic for UP-955 showing sand inflow encrusted onto tubing tail.

Analyses of Sand Consolidation on UP-955 Tubing Tail

The thin section, x-ray diffraction and SEM work revealed that the grain composition and grain size of the artificially cemented sands were the same as the formation sands and entered into the wellbore by means of the open perforations[7]. The sand grains flowed down the casing annulus between the casing and tubing tail, completely surrounding the tubing tail, as shown in Figure 8. The cemented sand samples indicated the presence of three concentrically arranged layers as described below and shown in Figure 9:

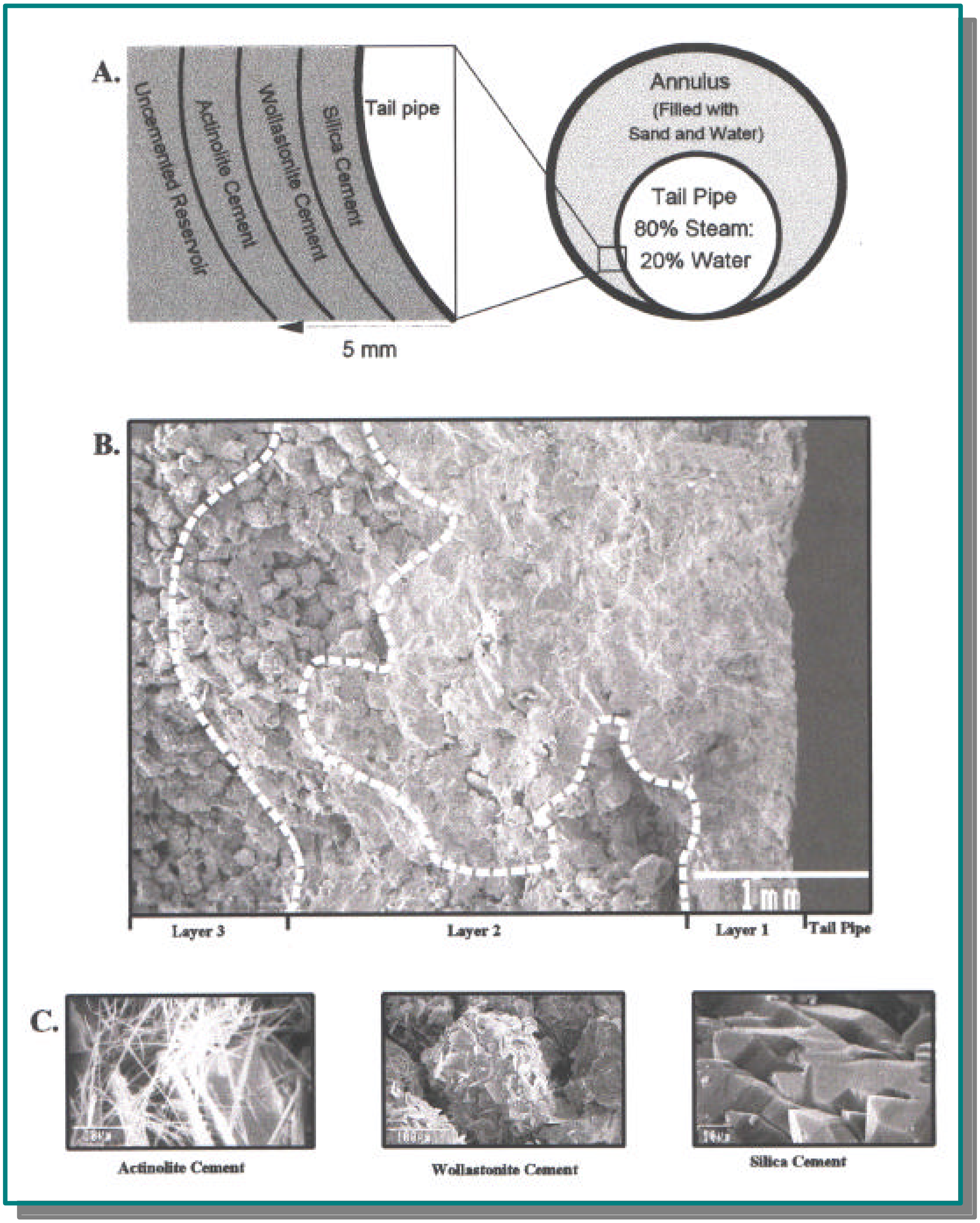


Figure 9 UP-955 tubing tail sample showing the three cement layers and the pictures of the three cement types bonding the sand grains.

Layer 1 was the closest to the tubing wall and consisted of sand grains bonded with silica cement (SiO_2). The 1 to 3 mm thick layer had a low porosity of < 1%, as determined from thin section analysis, and was considered to be essentially impermeable. Silica cement is a low temperature cement which precipitates at about 150°C. Layer 1 is believed to have been initially bonded with high temperature Layer 2 cements and subsequently covered with Layer 1 cements when cyclic steam injection ceased and the tubing filled with cool kill fluids. The silica cement occurs as grain coating chalcedony and as quartz overgrowths.

Layer 2 formed within and above Layer 1 and is 1 to 3 mm thick. This layer consisted of artificially cemented sand grains, primarily by a complex calcium silicate ($CaSiO_3$) mineral. The crystals formed a plate structure, which extended from one grain to the next. This layer had high porosity > 25% as determined by thin section analysis, however, a reduced permeability resulted from cemented pore throats. This layer is loosely referred to as the Wollastonite layer, as Wollastonite is the closest known mineral to this artificially-made cement. Wollastonite is a high temperature cement which precipitates at about 300^{o}C.

Layer 3 was the outermost layer and was 1 to 3 mm thick. Synthetic accicular (needle-like) crystals of another complex calcium silicate loosely cemented the sand grains. This layer has a high porosity > 25% as determined by thin section analysis. Permeability is higher than Layer 2 (by visual analysis), but like Layer 2, cannot be accurately determined reliably as the layers are too thin. This layer is loosely referred to as the Actinolite layer, as Actinolite is the closest known mineral phase of this artificially-made cement. Actinolite is also a high temperature cement which precipitates at about 250^{o}C.

Geochemistry of the Process

The use of the hot alkaline / steam sand consolidation technique to complete wells is based on the geochemical bonding of unconsolidated formation sand grains with a lattice of primarily high temperature complex synthetic silicate cements. In the case of well UP-955, the high temperature (> 250°C) synthetic silicates created contained calcium, magnesium, and iron[7]. Many relatively lower temperature precipitates are also created including other calcium and magnesium-based silicates, silica cements and sulfate, carbonate, and oxide scales [8]. The complex silicate cements and other mineral precipitates are created by the high temperature and high alkaline pH steam condensate which preferentially dissolves sand grains with high specific surface area[2,3,4,5] and that the framework sand grains, such as quartz, are less affected. The injected fluids rapidly lose heat to the formation and various cements precipitate with changes in temperature, alkalinity, and contact time. The lattice of cement bonds are created by the relatively high volume and high velocity steam vapor phase which dissipates through the near-wellbore region quickly and carries away excess cements and other precipitates where they do not adversely affect formation porosity and permeability.

Research by Reed[2] of Chevron USA and Watkins, et al[3] of Union Oil of California describe how high temperature and high pH fluids above 9.5 can cause significant silica dissolution of the gravel pack and formation sands. They discussed how typical oil field steam generators created 80% quality steam, of which the 80% vapor phase was slightly acidic (pH of 5-7) and the 20% liquid condensate phase was highly alkaline (pH of 10-12) based on the bicarbonate (HCO_3) content of the steam feedwater. The bicarbonate ions decompose into CO_2 and H^+ ions which partition to the vapor phase and make it acidic and OH^- ions which partition to the liquid phase and make it alkaline.

Research by McCorriston, et al of Gulf Canada, Sydansk of Marathon Oil, and Caballero of Advanced Technology Laboratories[4,5,6] touch on the geochemical reactants created by injecting steam into the formation and the resultant precipitates which can fill the pore spaces between the formation sand grains and gravel pack. The geochemical reactants include the sand grain minerals dissolved by the high temperature highly alkaline steam condensate and the minerals and salts in the steam feedwater and the formation oil, gas, and water. Figure 10 shows the typical water analyses for the steam feedwater and the pre- and post-steamflood formation waters for the Tar II-A project.

In summary, the complexity of analyzing the dissolved geochemical reactants created from sandstone dissolution was recognized in previous research, but generally for adverse effects. That research was concerned about silica dissolution of gravel packs, the related well failures, and formation damage from plugging the pore spaces with precipitates, primarily silica cements and acid insoluble silicates and scales. All of the tests were performed in the laboratory, usually at temperatures and pressures below 250°C and 700 psia. Some researchers mentioned the possible benefits of sandstone dissolution, such as increased porosity and permeability from dissolving sand grains and creating water-soluble silicates for enhanced oil recovery, but did not elaborate in their papers.

Analyses of Produced Water and Steam Feedwater

Selected Radicals	Steam	Pre-Steam Wells	Post-Steam Wells
Calcium	0.2	500	0 - 200
Magnesium	0.1	500	5 - 50
Iron	0	0.7 - 3.0	0.3
Silica	0	50 -100	100 - 200
Sodium	200	9500	1000 - 3000
Chloride	260	17,000	2000 - 4000
TDS	600	29,500	4000 - 9000

Figure 10 Typical Water Analyses of Steam Feedwater and Formation Waters

Influence on Permeability

The precipitation of synthetic cements reduces the permeability of the formation sands because the cements occur in the pore throats. However, the effective formation permeability in the near-wellbore region is probably greater following a sand consolidation treatment because of sandstone dissolution that creates secondary porosity and permeability. As mentioned previously, the dissolution reactions show selectivity towards grains with inherent planes of weakness and high specific surface areas. In this case, feldspathic grains appear to be extensively leached as shown in Figure 11. Due to the high abundance of feldspathic grains in the Tar II-A, extensive dissolution is apparent in the cemented sand samples, especially where several feldspathic grains occur in series. This group dissolution forms wormholes that have significantly larger pore throat channels than the natural intergranular pores. This phenomenon increases absolute permeability and explains the high productivity and injectivity indexes for the sand consolidated wells. This phenomenon could also be increasing relative oil permeability as evidenced in the production performance of certain wells. These dissolution wormholes appear to form only in areas of high heat transfer - immediately adjacent to the wellbore in steam injection wells. No evidence of wormholes or precipitates from the dissolution process has been observed in post-steamflood cores.

A closer analysis of the Wollastonite and Actinolite crystals reveals the presence of loose cement bonds between the sand layers. This is due to the habit (shape) of the said crystal layers. The loosely bonded nature of the Wollastonite and Actinolite layers implies that the rock framework is stabilized but not rigid. Thus, the skin around the perforation is correspondingly loosely cemented and can fail in the presence of high differential pressures across the formation face that has occurred in several wells. These types of well failures have generally been repaired successfully by applying another alkaline hot water/steam sand consolidation treatment.

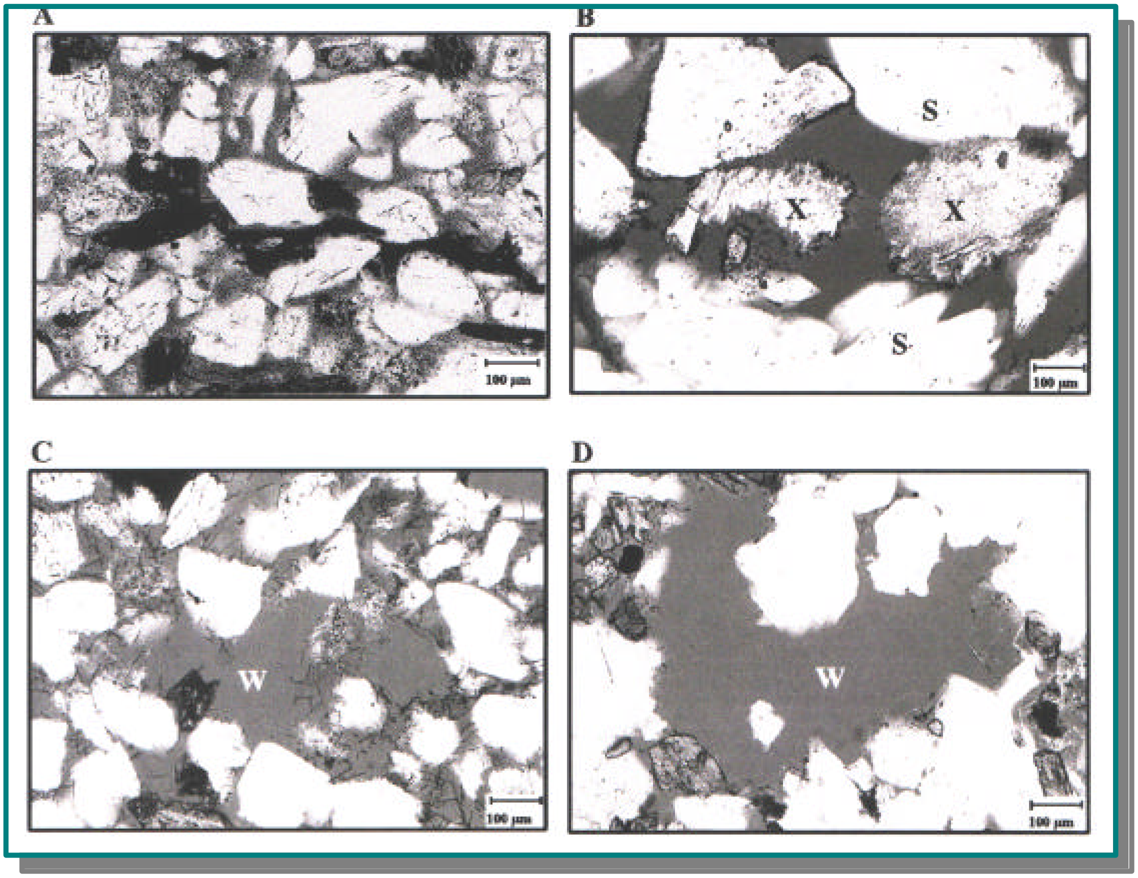


Figure 11 Thin section photomicrographs of pore structure. Sand grains are white and black; pores are gray areas between sand grains.
A. Actual pore structure of Tar Zone Sands (pre-steam core).
B. Partial dissolution of unstable grains (X).
Note: irregular grain outlines. Surrounding sand grains are relatively large due to precipitation of silica cement (S).
C&D. Dissolution wormholes (W) produced through leaching of pre-existing silicate grains.

Results and Conclusions

1) The Sand Consolidation Technique has seen successful applications on 13 vertical wells, 12 horizontal wells, 7 recompletes, and two repaired liners in three heavy oil zones in Fault Blocks I, II-A and V in the Wilmington Field. After 2 years of production and injection well service, over 90% of the wells experienced minor or no sand inflow problems. The application in horizontal wells has significantly reduced the risk of wellbore completion failures.

2) The Sand Consolidation Technique can provide substantial cost savings in well drilling and completion operations by eliminating the need for “conventional” opened-hole gravel-packed slotted-liner completions and replacing it with a simple cased-through and cemented completion with a limited number of selected small perforations. The wells completed with this technique have equivalent to higher production or injection rates than wells with the “conventional” completions due to increased permeability from sandstone dissolution.

3) The limited-entry perforating used in the Sand Consolidation Technique provides superior production and injection profile control in the treated wells. The treated wells can easily be reworked to eliminate unwanted perforations and to recomplete and treat new perforations.

4) The synthetic cements bonds tend to resist hydrochloric acid and therefore the wells with Sand Consolidation Treatments can be acidized to remove scales and other formation damage.

5) The Sand Consolidation Technique allows both production and injection wells to be completed the same way, thereby making it possible to convert wells easily to either service.

6) The Sand Consolidation Technique appears to work best in “dirty” sandstone reservoirs, those with chemically complex and unstable sand grains that are typically sensitive to foreign fluids or easily move in the reservoir, both causing formation damage. The sand consolidation process preferentially dissolves the sand grains with high specific surface area and, where several affected grains are connected, leaves “wormholes” in the near-wellbore region that enhance well performance.

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TABLE 1
WILMINGTON FIELD
SAND CONSOLIDATION JOBS
NEW VERTICAL WELLS

					Well Completion Data					Max Stabilized Rates		
Well	Flt Blk	Zone	Well Length MD/TVD	Well Type	Date (Mo/Yr)	No. Perfs	Perf Dia (in)	Interval Perfd (ft)	Cum Steam Treatment (BCWES)	Inj Rate (BPD)	Prod Rate (BPD)	PUMP FL (FOP)
2AT-049	2A	Tar	2890 / 2688	SF Inj	09/90	7	0.25	2748 - 2823	2,215,000	1000 S	N/A	N/A
2AT-052	2A	Tar	2848 / 2000	SF Inj	11/90	13	0.25	2517 - 2770	3,517,000	1440 S	N/A	N/A
2AT-053	2A	Tar	2800 / 2715	SF Inj	08/91	80	0.25	2694 - 2714	3,090,000	1500 S	N/A	N/A
2AT-055	2A	Tar	2721 / 2658	SF Inj	09/91	42	0.25	2634 - 2695	2,600,000	1500 S	N/A	N/A
2AT-054	2A	Tar	2768 / 2663	SF Inj	10/91	22	0.25	2690 - 2712	3,201,000	1500 S	N/A	N/A
2AT-056	2A	Tar	2896 / 2801	SF Inj+Prod / WF Inj	03/93	20	0.50	2772 - 2782	21,000	4500 W	1400	N/D
					09/93							
2AT-057	2A	Tar	2883 / 2757	SF Inj+Prod	03/93	58	0.25	2764 - 2824	24,000	1000 S	1450	900
					10/93							
2AT-058	2A	Tar	2883 / 2763	SF Inj+Prod	04/93	56	0.25	2751 - 2826	13,000	1200 S	1600	1200
					11/93				26,000			
2AT-059	2A	Tar	2900 / 2745	SF Inj+Prod	05/93	20	0.25	2778 - 2860	5,000	1150 S	1550	1850
					08/93	60	0.25		55,000			
					02/94				50,000			
UP-951	2A	Tar	3016 / 2799	SF Prod+Inj / WF Inj	06/94	79	0.31	2866 - 2982	60,000	4500 W	1300	N/D
UP-952	2A	Tar	3058 / 2789	SF Prod+Inj	06/94	64	0.31	2912 - 3008	45,000	1100 S	1100	2100
UP-953	2A	Tar	2952 / 2801	SF Prod+Inj / WF Inj	07/94	79	0.31	2806 - 2916	67,000	4000 W	1350	N/D
UP-954	2A	Tar	3133 / 2815	SF Prod+Inj	07/94	68	0.31	2954 - 3060	55,000	1200 S	1450	N/D

TABLE 2
WILMINGTON FIELD
SAND CONSOLIDATION JOBS
NEW HORIZONTAL WELLS

					Well Completion Data					Max Stabilized Rates		
Well	Flt Blk	Zone	Well Length MD/TVD	Well Type	Date (Mo/Yr)	No. Perfs	Perf Dia (in)	Interval Perfd (ft)	Cum Steam Treatment (BCWES)	Inj Rate (BPD)	Prod Rate (BPD)	Pump FL (FOP)
1T-001	1	Tar	3520 / 2487	Cyclic	07/93	140	0.50	2890 - 3500	72,000	2300 S	2500	750
SF-001	1	Tar	3510 / 2555	Cyclic	02/94	160	0.50	2890 - 3500	160,000	1600 S	3100	N/D
2AT-061	2A	Tar	4357 / 2438	Cyclic / SF Inj	12/95	11	0.25	3972 - 4302	146,000	1770 S	1800	N/D
2AT-063	2A	Tar	4726 / 2418	Cyclic / SF Inj	12/95	11	0.25	4240 - 4705	186,000	1400 S	1450	1300
FJ-202	5	Tar	4475 / 2114	Cyclic / SF Inj	04/96	14	0.29	3730 - 4470	97,000	2100 S	1550	40
FJ-204	5	Tar	4141 / 2126	Cyclic / SF Inj	05/96	14	0.29	3600 - 4050	119,000	1800 S	900	450
UP-955	2A	Tar	4466 / 2432	SF Prod	06/96	48	0.30	3915 - 4430	114,000	1800 S	2450	1250
UP-956	2A	Tar	4805 / 2374	SF Prod	06/96	36	0.22	4230 - 4710	183,000	1800 S	2000	1600
J-205	5	Tar	4145 / 2130	SF Prod	08/96	45	0.29	3388 - 4094	167,000	1900 S	1100	150
J-203	5	Tar	4648 / 2127	SF Prod	11/96	44	0.29	3745 - 4640	122,000	1300 S	1600	1450
J-201	5	Tar	4800 / 2111	SF Prod	01/97	46	0.29	3742 - 4125	169,000	1300 S	1250	400
J-017RD	5B	UT	4110 / 2849	Cyclic	05/97	40	0.29	3285 - 3900	91,000	820 S	900	1200

TABLE 3
WILMINGTON FIELD
SAND CONSOLIDATION JOBS
VERTICAL WELL RECOMPLETES / LINER REPAIRS

Well	Flt Blk	Zone	Well Length MD/TVD	Well Type	Well Completion Data: Date (Mo/Yr)	No. Perfs	Perf Dia (in)	Interval Perfd (ft)	Cum Steam Treatment (BCWES)	Max Stabilized Rates: Inj Rate (BPD)	Prod Rate (BPD)	Pump FL (FOP)
UP-779 Rec	2A	Tar	2750 / 2722	SF Prod	12/91	80	0.25	2675 - 2695	60,000	1000 S	700	N/D
UP-836 Rec	2A	Tar	2927 / 2919	SF Prod	08/92 05/95	120	0.50	2540 - 2570	20,000 67,000	1250 S	600	N/D
2AT-019 Rec	2A	Tar	2724 /	SF Waste Gas Inj	12/92	40	0.25	2530 - 2550	30,000	GAS	N/A	N/A
UP-932 LR	2A	Tar	2830 / 2552	SF Prod	10/94	SLOTTED LINER		2568 - 2828	51,000	1050 S	1400	N/D
J-015 Rec	5	TB	2415 / 2393	Cyclic	05/96	31	0.49	2310 - 2345	93,000	1600 S	980	1200
J-120 Rec	5B	UT	3080 / 2927	Cyclic	05/96	21	0.48	2993 - 3009	19,000	325 S	450	2300
J-046 Rec	5	TB	2400 / 2328	Cyclic	12/96	148	0.41	2345 - 2387	144,000	1100 S	1050	700
Z-061 Rec	5	Ranger	2600 / 2463	Cyclic	03/97	18	0.29	2471 - 2509	15,076	750 S	350	200
UP-924 LR	2A	Tar	2670 / 2533	SF Prod	11/97	SLOTTED LINER		2404 - 2667	78,000	1500 S	750	600